Analysis of the effectiveness of the alternating water and gas injection method (WAG)

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Abstract**—***Being the main source of primary energy in the world, oil is an increasingly used resource, and at the same time more difficult to be explored and produced. Special recovery methods have been extensively studied to increase the oil recovery. The WAG method consists of the alternating injection of water and gas for the recovery of the residual oil in the reservoirs. The objective of the present work is to simulate the alternating injection process and to evaluate its recovery efficiency when compared to the water injection and CO_2 injection method using the MRST software (Matlab Reservoir Toolbox Simulator). In general, an increase of about 4% in oil production was found, when the WAG methods and CO_2 methods are compared.The results show that, for three scenarios analyzed, up to 12 years of production the water flooding has the same volumes of recovered oil as the WAG or CO_2 mechanisms. After that period, the WAG mechanism resulted in greater volumes of oil produced.*

Keywords**—Carbon dioxide, EOR, Petroleum, Reservoir engineering, WAG, MRST.***

I. INTRODUCTION

The constant evolution of technology, which provides a better quality of life for society, is closely related to an increase in global energy demand. This increase in turn leads to an accelerated pace of high investments in the search for new sources of energy and/or improvement of existing ones. However, according to the IEA (International Energy Agency), fossil fuels account for about 81% of the world's primary energy. Of this total, 54% are still oil and natural gas exploring and production [1]

Both the burning of these fuels and the petroleum and gas exploration and production leads to a large amount of CO_2 emitted to the atmosphere, which has created a worldwide discussion on what to do with this gas and how to reduce its emission rate. CO_2 emissions become a challenge for the exploration and production of pre-salt reservoirs. Petroleum in the pre-salt reservoirs in Brazil has very high gas-oil ratio (GOR) with high content of carbon dioxide[2] According to [3] there are three ways to reduce the accumulation of these gases in the air: increase the efficiency of energy production, i.e. produce a smaller amount of CO_2 per unit of energy; use of renewable energies; CO_2 capture for use in enhanced oil recovered (CO_2-EOR) and geological storage (part of the CCS technology). In the CCS technology the produced gas with high content of CO_2 is treated at the production platform or in a subsea CO_2 separation process [4].

In the CO_2-EOR process the remainder gas with CO_2 content of 70% to 80% is reinjected into the reservoirs in the initial age of the reservoirs production. Where it mixes with the oil to swell it and reduce the oil viscosity, making it lighter and detaching it from the rock surfaces. However not all the injected CO_2 is produced, as a significant fraction of the CO_2 is retained in the reservoir. Therefore, the CO_2-EOR process is essentially a closed loop for CO_2[5]. Then, to maintain a specified injection ratio of CO_2, the recycled CO_2 is supplemented with the purchased CO_2, contributing to the reduction of CO_2 emissions from the atmosphere. However, CO_2 has a lower viscosity than

oil and therefore tends to form finger, reaching the producing well before oil -in other words the breakthrough time shorter than oil. One way to avoid this is to switch water and CO_2 injection, designated as "water-alternating-gas" or WAG floods.The amount of oil that can be recovered by a recovery method is a function of both geological and operational characteristics. Reservoir specificity such as lithology, permeability, heterogeneity, and other physical features unique to the reservoir influence efficiency as well as injection pattern (the geometrical arrangement of injector and producer wells), the distance between injectors and producers, the volume of fluid injected, and the ratio of injected water to injected CO_2 or "WAG ratio". Numerical simulation tools could be used to take these variables in consideration and help predict the overall behavior of a recovery method, and which configuration will give better results.

There are several computational tools to solve the porous flow problem. However, most are commercial and blackbox software that are expensive and donot allow changes in the code to better suit a specific scenario. Several groups of researchers have been developing free computational tools. In this work, simulations were performed in the software developed by the Computational Geosciences group in the Department of Mathematics and Cybernetics at SINTEF Digital - MRST, an open source program that is also free. Several recovery scenarios: water injection, CO_2 injection and WAG injection were analyzed to find the best method and the results were compared with the paper of [6].To verify the efficiency of the WAG recovery method compared to the continuous injection of CO_2 and water injection methods through free MRST software.The period evaluated in the production well were divided in 0-8 years (short), 8-24 years (medium) and 24-32 years (long). Injection methods were compared over different time periods: short / medium and long term and the permeability influence was check. The flow injected rate used to evaluated which method production were in stb/d: 12,000; 20,000; 30,000; and 45,000.

II. THEORETICAL FOUNDATION

Petroleum reservoirs are multiphase systems composed of oil, gas, and formation water. Oil recovery is a mechanism that depends on several factors which correlate the physical properties of the rock and the fluids involved. Due to the multiphase characteristic of the system there is a discontinuity of pressure at the interface between two fluids and the fluids and porous medium, resulting in capillary pressure. In a recovery mechanism that injects water, even if all oil trapped in the reservoir is in contact with water not all oil will be recovered, mainly due to high interfacial tension (IT) between oil and water or by forces capillaries. For an efficient recovery method, a displacement fluid with surface and interfacial properties ideal for mastering high IT and capillary must be injected into the reservoir. Thus, the recovery method should increase the overall oil displacement efficiency, which is a function of microscopic and macroscopic efficiency. The microscopic efficiency significantly depends on the relative permeability, interfacial tension, wettability, liquid viscosity, and capillary pressure. The macroscopic or volumetric sweep efficiency depends on the injection well pattern, fractures in the reservoir, position of gas-oil and oil-water contacts, reservoir thickness, heterogeneity, mobility ratio, density difference between the fluids [7].

The reservoir recovery efficiency, E_R, is given by the product between the displacement efficiency, E_d, and the volumetric sweep efficiency, E_V(Equation 1)

$$E_R = E_d . E_V \quad (1)$$

The **Error! Reference source not found.**shows microscopic and macroscopic efficiency on the reservoirs, E_d and E_V, respectively[8].

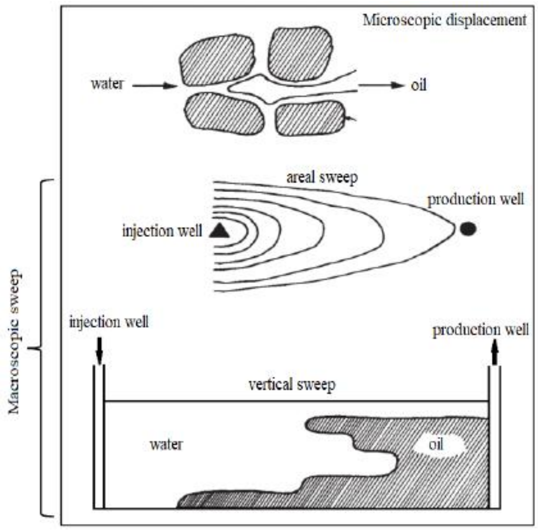

Fig.1: Schematic representation of macroscopic vertical sweep and microscopic displacement. Adapt from [9].

Displacement efficiency, E_d, is attributed to the produced oil from the pore spaces by the displacing fluid. It measures the oil saturation reduction in the invaded region by the injected fluid, E_d(Equation 2)is given by:

$$E_d = \frac{S_{oi} - S_{or}}{S_{oi}} \quad (2)$$

Where S_{or} is the residual oil saturation at the end of the displacement fluid injection and S_{oi} is the initial oil saturation.

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The volumetric sweep efficiency, $E_{v,}$corresponds to the amount of produced oil which has been in contact with the injected fluid [8]. It is a macroscopic measure between the products of the areal and vertical sweep efficiencies, E_A and E_{VV}(Equation 3):

$$E_V = E_A . E_{VV} \quad (3)$$

Water flooding is the most common method of oil recovery. Usually after water flood, significant amount of oil remains in the reservoir (S_{orw}), typical 40-60%, mainly due to high interfacial tension. Part of this remaining oil can be recovered by gas injection. Various types of gas have been used for injection in oil reservoirs including, CO_2 (mostly in USA), hydrocarbon gas (mostly in the North Sea area), nitrogen and air [10].

The injection of CO_2 as a component of an advanced oil recovery method acts at the interface between the phases, to reduce interfacial tension (IT) among them. For this, two factors influence the efficacy of this objective: the number of capillarity Ca and the ratio of mobilities M.

The capillary number Ca (Equation 4)brings the relationship between the viscous forces and the dominant capillary forces in the reservoir pores. This value is defined by Green and Willhite (1998) as:

$$Ca = \frac{v\mu}{\sigma} \quad (4)$$

where v is the Darcy velocity (m/s), μ is the viscosity of the shifting fluid (Pa*s) and σ is the interfacial tension between the phases (N/m).

The literature shows that the increase in the number of capillarity results in a lower value of residual saturation of the oil [11], that is, when it is said that the miscible methods act in the reduction of interfacial tension, the objective is the increase in the number of capillarity and consequently higher production of hydrocarbons.

The mobility ratio M (Equation 5)is the ratio between the mobility of the displacing fluid λ_d and the mobility of the displaced fluid, λ_o defined by the equation:

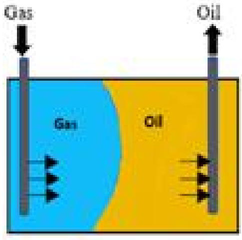
$$M = \frac{\lambda_d}{\lambda_o} = \frac{k_d}{k_o}\frac{\mu_o}{\mu_d} \quad (5)$$

where k is the permeability relative to each fluid, and μ is the viscosity of each fluid. The displacing and displaced fluids (oil) are represented by the subscripts d and o respectively.

The mobility ratio demonstrates the efficiency of the injection process. This value is considered favorable when close to 1 and corresponds to a slow advancement of the displacing fluid, creating a more uniform displacement front. This process increases the sweeping efficiency of the reservoir, i.e. a greater amount of oil is produced through the injection[11].

The great difficulty encountered in the pure CO_2, injection process is the difference between the viscosity and density of the gas and the oil. This discrepancy is clearly noted in the mobility ratio, which reaches values much greater than 1. Thus, the CO_2 forward front is not uniform (as shown in Figure 2a) and creates preferential paths through segregation and viscous fingering (Figure 2b) and arrives at the production well in an early manner. This phenomenon is called breakthrough.However, even so, according to [12] the preference in the use of CO_2 when compared to the other gases can be explained by its ease in mixing with the lighter fractions of the oil, going from C2 – C6.

To compensate for the effects caused by differences in density and viscosity, CO_2 is commonly injected into banks, characterizing the alternating water and gas injection (WAG) method (



(a)

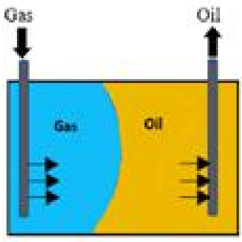
(b)

- Viscous fingering
- Early gas breakthrough
- Gravity segregation
- Heterogeneities effects

(c)

- Better sweeping efficiency than GI
- Less adverse effects compared to GI (i.e., gravity segregation, early breakthrough, viscous fingering, heterogeneity effects

Fig.1).



(a)

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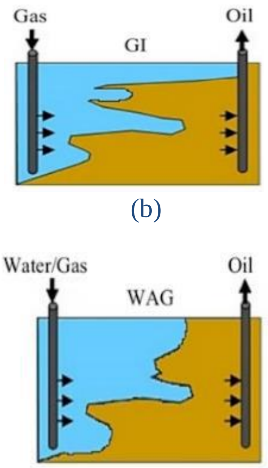

(b)

- Viscous fingering
- Early gas breakthrough
- Gravity segregation
- Heterogeneities effects

(c)

- Better sweeping efficiency than GI
- Less adverse effects compared to GI (i.e., gravity segregation, early breakthrough, viscous fingering, heterogeneity effects

Fig.1: Representation of three differentcases for CO_2injection. In (a) the uniform/ ideal advance of the CO_2 bank. In (b) the influence of density and viscosity on the forward front. In (c) the conventional WAG injection. Adapted from [13].

According to [13] the WAG method reduces the rate of mobility between the gas and the oil, and consequently increases the efficiency of sweeping the reservoir. While the CO_2 front contacts the residual oil by removing the heavier fractions and reducing the density difference between gas and oil, the water front reacts with the CO_2 bank increasing its viscosity. Fig.2shows the structure of the injection seats showing a schematic of the injector and the productor well and the oil bank, miscible, water and CO_2 zone. Is possible to observe that the WAG scheme (water and gas injection) are carried out alternately in a reservoir for a period of time in order to provide both macroscopic sweep and microscopic efficiencies and reduce gas override consequences: viscous finger, gas breakthrough and gravity segregation [14]. However, the method has a complex three-phase flow in the porous medium.

In the miscible zone, there is a continuous mass transfer between the CO2 and the reservoir oil, which improves the density and viscosity of the fluid in this zone. In addition, reducing interfacial tension in the miscible zone allows for better oil recovery. However, for these miscible zones to occur, the pressure at the gas / oil interface must be greater than the minimum miscibility pressure (PPM). This pressure value is a parameter that defines whether the process will be miscible or not. Therefore, maintaining the efficiency of CO_2 injection also means achieving and maintaining PPM [16]. The calculation to estimate the value of the minimum pressure for the CO_2 can be done through some correlations; as proposed by [17] which is still widely used; or more recent ones, such as that developed by [18].

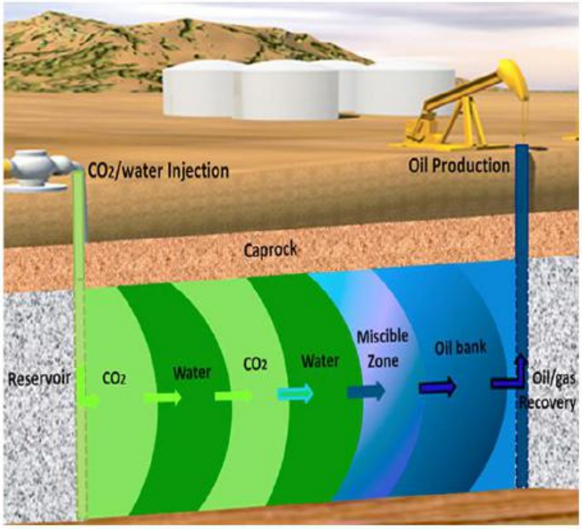

Fig.2: Scheme of injection in banks in the WAG method[15].

There are, according to the literature, some criteria regarding the fluid and the reservoir that must be respected to obtain a CO_2 injection with high efficiency. They are: the porosity must be greater than 15%, the fluid must have a density greater than 25 º API and viscosity lower than 12 cP; the reservoir pressure should be between 1500 and 6000 psi; being in an advanced stage of water injection or other secondary recovery method [3].

According to [19] the number of fields that have adopted miscible injection methods has increased by 41% in recent years, and since 2006, gas injection has been the main method of recovery in the United States in terms of number of projects. In addition, the miscible injection of CO_2 Water Alternating Gas is one of the ways to help offset the cost associated with CO_2 geo-sequestration processes making them economically more attractive [20].

In Brazil, according to [20] the alternating injection method is used in 8 wells, most of them in the Lula field. The results found in the production, according to the [21] are satisfactory, and the method is very promising for the pre-salt, mainly due to the high concentration of CO_2 in the reservoirs.

III. METHODOLOGY

The simulations were performed using the MRST computational tool. The oil production was evaluated during a total period of 32 years of production. Were analyzed 3 scenarios with 4 distinct cases of recovery mechanism, being: case 1 - natural flow well; case 2 -

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water flooding; case 3 - CO_2 injection and case 4 - WAG injection.In all cases, the upwelling production was maintained for two years.

The simulations of the first scenario were made to validate the model. The obtained results were compared with the results found by [6]. Those results obtained measure the efficiency of each recovery mechanism, by the determination of their production in all four cases. The case 1 will be used for comparison of the effectivity of the production in cases 2, 3 and 4.

For the second scenario the analyses of oil production were evaluated in different times periods: short term (0-8 years), medium term (8-24 years) and long term (24-32 years).

3.1 Proposed Issue

For the simulations, the reservoir size data and rock and fluid properties were based on the study by [22].

The reservoir is characterized as a parallelepiped, being completely horizontal. It has dimensions of 1066.8 m x 1066.8 m x 30.48 m, in the X, Y and Z axes respectively, with its first layer at the top, located at 2537.46 meters in depth. There are two wells in the reservoir, an injector, and a producer, arranged diagonally. The reservoir parameters can be found in Table 1andTable 2.

Table 1: Reservoir conditions parameters.

Parameter	Value
Porosity, %	30
Rock compressibility, 1/Psi	$5*10^{-6}$
Initial pressure, Psia	4000
Temperature, K	344.261
Deep, m	2537.46
Oil saturation, %	80
Water saturation, %	20
Saturation pressure, Psia	2302.3
Distance between wells, m	4005

(Adapted from [22]).

Table 2: Layer Parameter

Layer	Vertical Permeability (mD)	Horizontal Permeability (mD)	Thickness (m)
1	50	500	6.069
2	50	50	9.144
3	25	200	15.24

(Adapted from [22]).

The analyzes of the methods were performed through simulations in the free software MRST (Matlab Reservoir Simulation Toolbox). The properties used in the study of [22] was used as input data in the simulator.

The model that will be used corresponds to the set of equations determined black oil. The name refers to the assumption that the various chemical species present in petroleum can be grouped into two components under surface conditions, a heavy hydrocarbon component called "oil"; and another with light hydrocarbons, called “gas".

Under reservoir conditions, the two components may dissolve in each other depending on the pressure and temperature conditions, forming one or two phases. In addition, the model also includes an aqueous phase, composed only of water. Despite all the interactions between the phases, the composition of the hydrocarbon remains constant.

3.2 Mathematical formulation

3.2.1 Porosity

The porosity φ of a medium is defined as the ratio between the empty spaces of the rock over its total volume, thus its value varies from $0 < \varphi < 1$.

For a model considering the incompressible rock, the porosity can be considered as a function of the pressure, as shown in the following Equation (6).

$$\emptyset(p) = \emptyset_0 e^{c_r(p-p_0)} \quad (6)$$

where p is the total pressure of the reservoir, p_0 is the initial pressure, and c_r as the compressibility of the rock. For a simpler equation, the porosity value can be linearized by Equation (7):

$$\emptyset = \emptyset_0[1 + c_r(p - p_0)] \quad (7)$$

3.2.2 Saturation

The saturation S_α is defined as the fraction of pore volume occupied by a given phase α. In the multi-phase model used, it is assumed that all empty space is filled by fluids (Equation 8), therefore:

$$\sum_\alpha S_\alpha = 1 \quad (8)$$

In the model presented, three phases are considered: one aqueous phase (w), one gas phase (g), and another oil phase (o). The saturation value for each of the three phases can range from 0 to 1.

3.2.3 Black-oil Model

In the Black Oil Model, the fundamental principle of mass conservation is used. For a multiphase and multi-component system, the equation for each phase is (Equation 9, 10 and 11),

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$$\partial_t(\emptyset b_o S_o) + \nabla * (b_o \vec{v}_o) - b_o q_o = 0 \quad (9)$$

$$\partial_t(\emptyset b_w S_w) + \nabla * (b_w \vec{v}_w) - b_w q_w = 0 \quad (10)$$

$$\partial t\left[\emptyset * \left(b_g S_g + b_o r_{so} S_o\right) + \nabla * \left(b_g \vec{v}_g + b_o r_{so} \vec{v}_o\right) - \left(b_g q_g + b_o r_{so} q_o\right)\right] = 0 \quad (11)$$

where $\emptyset$ represents the porosity, ρ the density value, S the saturation, $\vec{v}$ is the velocity and q correspond to the flow rate and the subscript α indicates the phase being analyzed. The value of b_l, b_o, b_g which correspond to the inverse of the formation volume factor (for each phase), the ratio $r_{so} = \frac{V_g^s}{V_o^o}$ defines the solubility ratio gas-oil.

The velocity ($\vec{v_\alpha}$) is calculated by Darcy's law (Equation 12):

$$\vec{v}_\alpha = \frac{-K k_{r\alpha}}{\mu_\alpha}(\nabla p_\alpha - g\rho_\alpha \nabla z) \quad (12)$$

the variable $\mu_\alpha$represents the viscosity of the fluid, $\rho_\alpha$is density, ∇p_α is the pressure gradient, $k_{r\alpha}$ represents the relative permeability of each phase.

3.2.4Numerical approach

Like the work of [6] the reservoir is composed of 147 cells distributed in: 7 cells in the X axis, 7 in the Y axis and 3 in the Z axis, as can be seen in

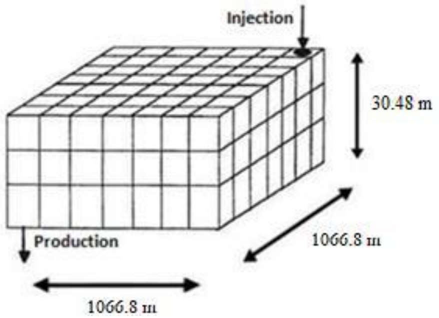

Fig.3.

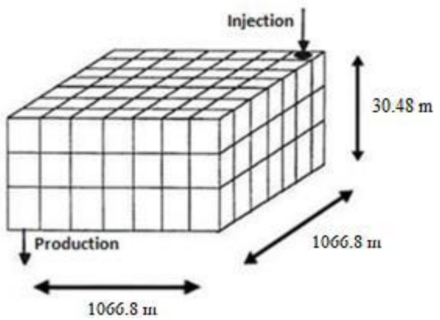

Fig.3: Discretization of the reservoir and positioning of the wells (Adapted from [6]).

The size of each cell in the X axis and Y is 152.4 meters. Already for the Z axis, the first layer is 6.096 meters, the second 9.144 meters, and the third 15.24 meters. To solve the problem, the finite difference method will be used [11].

3.2.6 Proposed Scenarios

For the validation of the MRST software the procedure of [6] will be reproduced and used for evaluating four cases:

Case 1 – Natural flow well;

Case 2 - Water flooding;

Case 3 –CO_2 injection;

Case 4 –WAG injection.

In cases 2, 3 and 4, the analyzed period was 32 years, and in the first years, no injection method was used, that is, natural flow. The values considered for the injection rate were 12,000 stb/d, 20,000 stb/d, 30,000 stb/d, 45,000 stb/d. The effectiveness of the method was determined by comparing the flow production rate.

After the model validation will be carried out an analysis of the production over the time.

IV. RESULTS AND DISCUSSIONS

4.1 First scenario: Software validation and method effectiveness

Simulations were carried out for the three recovery methods (case 2, 3 and 4) at different flow rates. The results were arranged in tables and compared with those obtained by [6].

Table 3shows the cumulative oil production data obtained for each injection method, with their respective flow rates.

Table 3: Production data for each recovery method.

Injection Methods	Flow rate stb/d	Software's		
		MRST	Eclipse	$Relative\ Error = \left(\frac{Eclipse - MRST}{MRST}\right) * 100\%$
		Cumulative Oil Production (MMstb)		
Natural flow well – Case 1	0	12.10	11.10	8.26
Water flooding – Case 2	12,000	24.47	26.40	7.89
	20,000	25.38	26.10	2.84
	30,000	25.73	25.50	0.89
	45,000	25.74	25.40	1.32
CO_2 injection	12,000	33.19	30.70	7.50
	20,000	36.56	34.10	6.72

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– Case 3	30,000	38.54	36.10	6.33
	45,000	40.28	38.70	3.92
WAG injection – Case 4	12,000	39.05	32.50	16.77
	20,000	40.52	35.00	13.62
	30,000	41.29	37.90	8.21
	45,000	42.03	40.60	3.40

Source: *(Author)*

For the first case, natural flow, we observed an estimate 9% higher in the cumulative oil production than the value estimated by the eclipse software. For better visualization the data of Table 3can be found inFig.4.

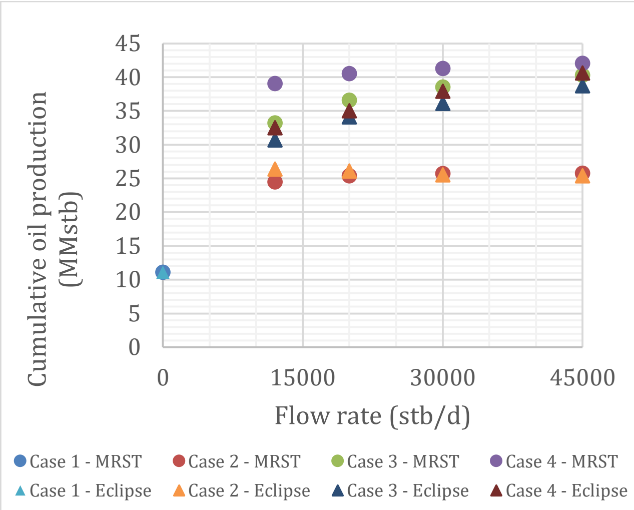

Fig.4: Cumulative oil production for case 1- natural flow; case 2 – water injection; case 3 – CO_2 injection and; case 4 – WAG injection.

Regarding the effectiveness of the method, it is possible to notice a continuum increase of cumulative oil production with the flow rate for the cases 2, 3 and 4 when compared to case 1. The use of WAG injection shown an increase of 3.47 times the production of natural well flow, proving that this method makes a better sweep of the reservoir elevating the production of the well.

For the three injection methods, it is possible to note a pattern of reduction of the relative error found, as the injection flow increases (

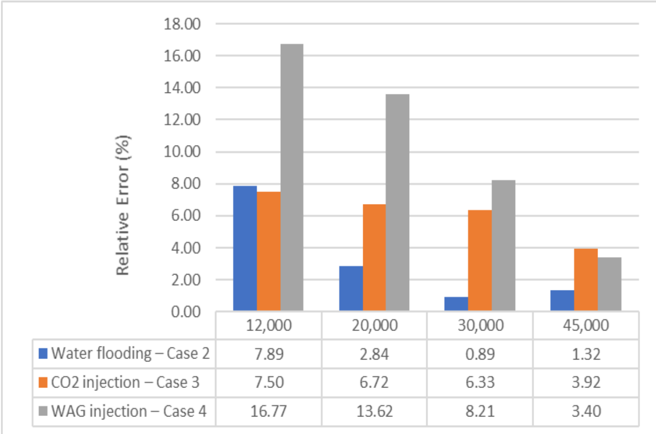

Fig.5). This behavior is evidenced mainly in the WAG injection, where for an injection flow of 12,000 stb/d a difference of 4.63 was found, while for the 45,000 stb /d flow the deviation was only 1.01.

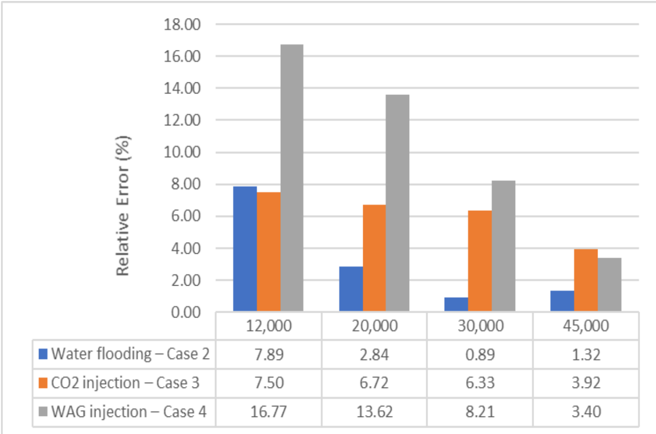

Fig.5: Behavior of the relative error with respect to the method and injection rate.

Therefore, despite less robust software, these results demonstrate the effectiveness of MRST, especially for simulations involving high fluid flows.

4.2 Second scenario: Analysis of production over time

To perform the production analysis, the injection rate of 12,000 stb/d, which generated the lowest production, for cases 2, 3 and 4.

Fig.6shows the production for the first 8-year period. After the first two years of emergence, the CO_2 injection method has a slightly higher recovery than the others, but is soon overcome by alternating injection, when it reaches stabilization in its cycles.

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Fig.6: Oil production in the first 8 years of simulation with injection of 12,000 stb/d for the three methods.

Therefore, at the end of the period it is observed that the WAG method is more efficient in the short term, followed by the injection of water and later that of CO_2. The fact that the injection of gases has an early breakthrough in relation to the injection of fluids, explains a smaller production of the method in the first years of production.

The results found are in agreement with [13] who states that the injection of the two fluids in cycles, behaves in a way that with each water bank, the advance of the injection front is retarded, and each CO_2 bank the miscibility with the oil is increased, resulting in an increase in recovery efficiency.

Fig.7below shows the data for medium-term production in the period from 8 to 24 years. For this time interval, as already expected, the alternating injection method still has higher production and an increasing curve in the recovered oil value.

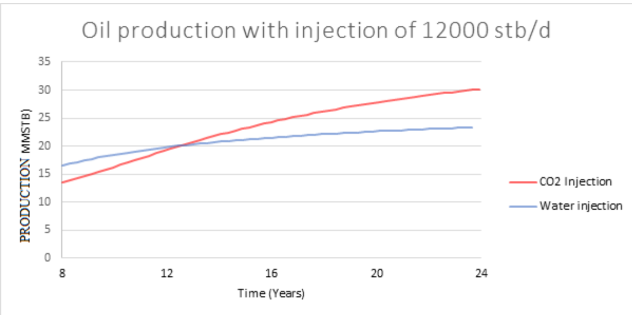

Fig.7: Oil production in the period from 8 to 24 years of simulation considering the injection of 12,000 stb/d for the three methods.

At the same time, it is possible to note the effects of miscibility between water and oil for such an injection method. During the 16 years, the production curve is tending to a certain stability, having an increasingly smaller production over time. This phenomenon can be explained by the difficulty that water has to cover the entire reservoir, together with the inability of water to remove the volumes of oil mopped by interfacial tension.

On the other hand, CO_2 injection shows exactly the opposite. While earlier production was smaller because of earlier breakthrough, now the ability of CO_2 to blend with the oil and reduce interfacial tension between the phases brings the possibility of producing the volumes that were previously mopped. This characteristic is confirmed by the greater production of oil through the injection of CO_2 from the 12th year of production.

The long-term production analysis, from 24 to 32 years of simulation, can be visualized inFig.8. It is possible to verify a stabilization of the production curves, which indicates that the three methods reached the maximum recovery efficiency for the if proposed.

Fig.8: Oil production in the period of 24 to 32 years of simulation. Injection of 12,000 stb/d for all three methods.

The results found in the second scenario followed the same pattern as in the first scenario. However, it was possible to identify that the water injection method, for the short term, is more efficient than CO_2injection. Thus, such behavior can be considered when choosing the injection method.

V. FINAL CONSIDERATIONS

In a general, the software has shown satisfactory results when it comes to simulation of injection methods. The 4% increase in oil production when compared to WAG-CO_2 methods was achieved. In addition, the deviations found between the values obtained through the MRST software and those of [6] were relatively low, mainly at high injection rates.

In general, an increase of about 4% in oil production was found, when the WAG-CO_2 methods are compared. In addition, the deviations found between the values obtained by the MRST software and those of [6] were a maximum

of 17%, decreasing to around a maximum of 7% for the largest simulated flows.

Likewise, it was possible to evaluate the effectiveness of each method in relation to the period of time the method was used. In general, it was observed that up to 4 years of production there are no significant differences in oil production. Up to 12 years, the water injection method is more efficient. After this period, the CO_2 injection method present greater volume of oil production. The WAG method presents the largest volumes of oil production throughout the analyzed period.

The use of the MRST software proves to be a great option for works related to reservoir engineering and recovery methods, among others. The possibility of accessing routines is a great advantage in relation to commercial software, as it allows new routines to be inserted. The software has a certain intuitiveness for its use as well as extensive documentation that can be found on the website:

https://www.sintef.no/projectweb/mrst/documentation/.

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